REVIEW AND ANALYSIS OF CHARLES RIVER ASSOCIATES' "ECONOMIC IMPACT OF INADEQUATE GENERATION IN ERCOT – COMPARISON OF RESOURCE ADEQUACY SCENARIOS"

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Charles River Associates (CRA) was commissioned by NRG Energy, Inc. (NRG) to prepare a study examining the economic impact of inadequate generation in ERCOT and to compare different resource adequacy scenarios (the CRA Study).[2] NRG subsequently filed the CRA Study in docket 40000 on August 27, 2013.[3] I performed this analysis of the methodology and assumptions used by CRA at the request of Commissioner Kenneth W. Anderson, Jr. in order to evaluate the accuracy of the CRA Study's results. While prepared at the request of Commissioner Anderson, the analysis, opinions and views expressed herein are entirely my own and do not necessarily reflect the views and opinions of the commissioner.

This evaluation of the CRA Study consists of three parts: **Part one** is an executive summary. **Part two** is a review of the methodology employed by CRA as well as a summary of my analysis of the data and assumptions used by CRA. **Part three** is an appendix that provides the details of the mathematics employed by CRA as well as the mathematics behind the assumptions used by CRA in their study. In the appendix, I provide additional calculations that I used in the evaluation of third party studies relied upon and referenced by CRA.[4] In the last section of the appendix I briefly discuss tangential issues that came up during my analysis of the CRA Study. For those intrepid souls who choose to go boldly where few people dare to tread, (and who probably have fond memories of their high school math teachers) please delve into part three so that you will have an in depth understanding of the methodology of the CRA Study as well as my analysis of CRA's work. Critique this analysis and file responses in this docket, as the objective of this report is to improve accuracy in order to provide the best information possible to the Commissioners who are tasked with making critical policy decisions that affect the Texas economy and all Texans.

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[2] Jeff Plewes & William Hieronymus, *Economic Impact of Inadequate Generation in ERCOT – Comparison of Resource Adequacy Scenarios*, (August 27, 2013).

[3] *Commission Proceeding to ensure Resource Adequacy in Texas*, Project 40000, item 449.

[4] For those who are mathematically timid, or perhaps have the occasional terrifying dream that they've been enrolled in a math class all semester, but somehow managed to never attend a class, and finals are approaching, you should feel comfortable sticking with parts one and two as you have the knowledge that the underlying math is out there in part three for others to review for accuracy.

PART 1: Executive Summary

Summary:

The CRA Study grossly overstates the direct cost per event of electric service interruption in its evaluation of the energy market construct. This is the value that CRA uses in their economic model to determine the effect on the Texas gross state product. In calculating the direct cost per event, CRA ignores warnings from the authors of a referenced national study and use summer weekday afternoon cost values for *every* time period of the year. Ignoring yet another warning from the same national study, CRA fails to account for a significantly higher load profile for afternoon and evening periods which also inflates their numbers. The inflation is so great that the CRA Study uses $85,000/MWh[5] as an overall *average* cost per un-served MWh (or $85 per un-served kWh), for every time period of the day, season of the year, business type and residential consumer. Finally, CRA assumes an 8.4%[6] reserve margin by way of incorrect assumptions and basic math errors for the energy market in 2016 to determine the total amount of un-served energy in a year[7], and they carry these errors throughout all years of their study. The net effect of these errors and omissions is to increase the cost estimate of an energy market by at least a factor of ten (likely by a factor of at least 40). Some, but not all, of the errors also affect CRA's results for the energy plus capacity market.

The CRA Study relies on the following:

- ERCOT Loss of Load Study of March 2013 (LOL Study).[8]
- ERCOT Resource Adequacy Study (RA Study).[9]
- The May 2013 ERCOT Capacity Demand and Reserves Report (CDR).[10]
- A study completed in June 2009 for the U.S. Department of Energy (DOE) by the Ernest Orlando Lawrence Berkeley National Laboratory (Berkeley Study).[11]
- Results from an economic modeling tool called "REMI."[12]

The CRA Study performs the following calculations:

- CRA determines the amount of un-served energy each year for a 15 year period.[13] Un-served energy is the amount of kilowatt-hours (kWh) of load that would be curtailed each year if load-shedding events occurred.

[5] *See* Part 2 of this analysis at 11.
[6] Plewes & Hieronymus, *supra* note 2, at 24, *see* footnote 29.
[7] Id. at 30, *see* Table 5.
[8] ECCO International Inc., *2012 ERCOT Loss of Load Study, Study Results*, March 8, 2013.
[9] Sam Newell et al., *ERCOT Investment Incentives and Resource Adequacy*, (June 1, 2012).
[10] ERCOT, *2013 Report on the Capacity, Demand and Reserves in the ERCOT Region*, (May 3, 2013)
[11] Michael J. Sullivan, Matthew Mercurio & Josh Schellenberg, *Estimated Value of Service Reliability for Electric Utility Customers in the United States*, (June 2009).
[12] Plewes & Hieronymus, *supra* note 2, at 29.
[13] *Id.* at 25.

- CRA then uses the Berkeley Study to provide values for cost per un-served kWh (in $/kWh) for three customer classes in 2012. This is done by taking values from a Berkeley Study table and converting them from 2009 values into 2012 values.[14]

- CRA then multiplies the amount of un-served energy by the cost per un-served kWh to get a direct cost in dollars (kWh x $/kWh = $) associated with a load shedding event.[15]

- This direct cost in dollars is then spread out over 160 sectors of the Texas economy and inserted into REMI. REMI then produces a total dollar value of the impact the direct cost would have on the Texas economy.[16]

- CRA does this for two market constructs over a 15 year period: The energy-only market construct and the energy plus capacity market construct. They then compare the results of each ($17.1 billion and $3.1 billion) and assert that over the 15-year period, the energy plus capacity market construct saves the Texas economy $14 billion.[17]

When I reached this particular spot in the CRA Study I felt it was time for a reality check. $17.1 billion is a whole lot of money! Just from load shedding events? For $17.1 billion, one can buy about six Virginia class, state of the art, nuclear powered attack submarines with $2 billion left over to arm them.[18]

Another way to consider $17.1 billion in cost from load shedding events, is to realize that load shed from loss of load events because of capacity shortfalls is only about 1% of all loss of load that occurs over time.[19] 99% of power outages are from equipment failures, lightning strikes, wind damage, etc. Whether a curtailment of load event because of capacity (1%), or power outage because of equipment failure or weather related loss (99%), the costs will be the same per kWh. Therefore, for the CRA Study to be correct, all power outages over the next 15 years would cost the Texas economy 100 times $17 billion, or $1.7 Trillion (that's with a capital T). This does not make sense for power outages, it did not make sense to me, and I felt that CRA was off by at least an order of magnitude (at least a factor of 10) in their study.

Errors in assumptions and calculations made by CRA and the impact of those errors:

- CRA takes a 2016 10.4% reserve margin from the CDR and assumes it corresponds to an 8.4% figure in the LOL Study. They make two mathematical errors and one significant assumption error that leads them to choose the 8.4% values from the LOL Study for use in the energy-only market construct. The mathematical mistakes alone result in more than a doubling of the direct cost computed by CRA and used in the REMI model. The assumption error also leads to a significant inflation of direct costs because it is safe to

[14] *Id.* at 26.
[15] *Id.* at 30.
[16] *Id.* at 30 - 32.
[17] *Id.* at 32.
[18] Fiscal Year 2012 Pentagon Spending Request, $4,954.9 million requested for two vessels.
[19] Newell, et al., *supra* note 9 at 4.

say that the actual reserve margin in 2016 will be higher than 10.4%, because CDR predicted reserve margins are historically low, the farther out they are predicted.[20] CRA carries these errors through all 15 years of their study.

- CRA themselves identify that the difference between a 13.5% reserve margin and an 8.4% reserve margin produces a 90% reduction in un-served kWh.[21]

- The CRA Study errs when they select values to be used for cost per un-served kWh. CRA references a "key" table from the Berkeley Study.[22] They then bring the 2009 values from this table forward to 2012 values and use these numbers in their determination of direct costs. The mistake is that the "key" table referenced in the Berkeley Study is <u>only</u> for summer weekday afternoons. They use the values from this table for dollar per un-served kWh for every time period throughout the year. *The Berkeley Study specifically warns against reliance on values from only one time period.* The Berkeley Study authors write, "This inherent variation in the cost of service interruptions is an empirical fact that should not be ignored for purposes of computational convenience. That is, it is not appropriate to just pick one of the interruption costs (for a specific season, day of the week and onset time of day)."[23] This further inflates the value of direct cost, in some instances by more than double (Summer weekday evening cost from Berkeley is $299 compared to afternoon cost at $610, since CRA only uses values from the summer weekday afternoon table, the evening values used by CRA are more than double, i.e. a factor of 610/299).

- The CRA Study ignores and carries forward an over simplification assumption identified by the Berkeley Study authors,[24] that results in CRA using values for dollar per un-served kWh from the Berkeley Study that in the afternoon and evening periods are likely 66.7% high (or should be only 60% of the value used by CRA). This further increases the value of direct cost used by CRA associated with electric service interruption.

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[20] *See* Summer CDRs for 2005-2010 for predicted values of peak load three years in advance. *See* also Trip Doggett, *ERCOT – A Strategic View of the Future*, presentation to Gulf Coast Power Assoc., at 4 for actual peaks. http://www.ercot.com/content/news/presentations/2013/GCPA%20-%2002%20Oct%202013%20FINAL.pdf. The CDR predicted peak demand three years in advance has been in excess of the actual peak demand. This leads to a higher firm load forecast, which in turn creates a lower than actual predicted reserve margin.

CDR Year	Predicted Peak Load (MW)	Actual Peak Load (MW) (CDR Year plus 3)
2005	64,245	62,174
2006	65,950	63,400
2007	67,955	65,776
2008*	68,964	68,305
2009	67,394	66,548
2010	68,265	67,180

* Even the prediction for 2011 was 1% too high.

[21] Plewes & Hieronymus, *supra* note 2, at 30.

[22] *Id.* at 26.

[23] Sullivan et al., *supra* note 11, at xxv.

[24] *Id*. at xxi.

- The CRA Study errors compound in the aggregate. This is, in the aim of identifying a direct annual cost, every input error exacerbates the derived direct cost of an event by the factor attributable to each input error. And this does not take into account the assumption error of the 10.4% reserve margin for 2016.

- All of this results in a significantly higher value for direct cost that CRA then injects into the REMI model to determine the impact on the Texas economy producing a result that is easily an order of magnitude too high (and likely 40 times too high)[25] for the energy-only market construct.

PART 2: Review of the Methodology and an Analysis of the CRA Study.

Review of the Methodology of the CRA Study:

CRA begins with the general and well received assumption that electricity is leveraged by businesses and people in their economic and personal endeavors in a manner that contributes to the gross state product.

<u>STEP ONE OF CRA METHODOLOGY</u>:

CRA utilizes the LOL Study,[26] the RA Study[27] and several CRA assumptions[28] to determine the amount of un-served energy that will result if a loss of load event were to occur in the ERCOT grid. CRA produces estimates for the amount of un-served energy in 2014 and 2016 while examining different reserve margins and also an estimate of the amount of un-served energy for an average year from their assumptions. The result of this approach is found in Table 3 of the CRA Study.[29] The term "amount of un-served energy" is a way of saying, "if ERCOT has to shed or curtail 1,500 MW of power for two hours, then there will be 3000 MWh of un-served energy." The CRA Study Table 3 determines this value for the years described, relying on the information from the ERCOT studies and the CRA Study basic assumptions. In Table 3, the amount of un-served energy is just the Average Outage Duration times the number of loss of load events times the amount of MW per event of power that is lost. For the 2014 estimated value found in Table 3, it is 2.4 hours times 0.4 events times 1,350 MW per event, equaling 1,310 MWh. I find no fault with this approach as the methodology appears reasonable. *I do, however, question CRA's use of a reserve margin of 8.4% in 2016.* After all, if the economic equilibrium reserve margin is at least 9.2%,[30] and the ERCOT market has been functioning for over 10 years, and we're well above that figure now, how is it that we have not equilibrated to 9.2% by now, and what would possibly make us think that over the course of the next three years we will descend below that figure to 8.4%? *The use of this value drastically overstates the*

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[25] *See* Part 2 of this analysis at 11.
[26] Plewes & Hieronymus, *supra* note 2, at 7.
[27] *Id.* at 6.
[28] *Id.* at 25.
[29] *Id.*
[30] Sam Newell, *ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates,* Project 40000, item 429.

number of loss of load events, which in turn inflates the expected un-served energy. However, it also introduces another factor for consideration: what is the annual amount of un-served energy attributable to things other than a lack of installed capacity? For instance, what is the amount of un-served energy attributable to weather related outages, or transmission and distribution equipment related outages? For comparison purposes, this un-served energy is just as important. I will briefly touch on this topic in the appendix.

<u>STEP TWO OF THE CRA METHODOLOGY</u>:

After estimating the annual amount of un-served energy in ERCOT *from a curtailment of load from a lack of installed capacity only*, CRA then assigns a dollar value to it by relying on the Berkeley Study.[31] One of the many results from the Berkeley Study is the estimated value of the cost (in dollars) per un-served energy (in kWh) for three different customer classes.[32] Because the Berkeley Study was completed in June 2009, CRA first converts the dollar values from the "key" table from the Berkeley Study into 2012 values.[33] CRA reproduces the Berkeley table in 2012 dollars and in the CRA Study it is listed as Table 4 (CRA Table 4).[34] I have reproduced it here for ease of discussion and also in the appendix to this memorandum alongside the table from the Berkeley Study[35] from which it was directly adapted.

Table ES- 1. Estimated Average Electric Customer Interruption Costs US 2008$ by Customer Type and Duration (Summer Weekday Afternoon)

	Interruption Duration				
Interruption Cost	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I					
Cost Per Event	$11,756	$15,709	$20,360	$59,188	$93,890
Cost Per Average kW	$14.4	$19.3	$25.0	$72.6	$115.2
Cost Per Un-served kWh	$173.1	$38.5	$25.0	$18.2	$14.4
Cost Per Annual kWh	$1.65E-03	$2.20E-03	$2.85E-03	$8.29E-03	$1.31E-02
Small C&I					
Cost Per Event	$439	$610	$818	$2,696	$4,768
Cost Per Average kW	$200.1	$278.1	$373.1	$1,229.2	$2,173.8
Cost Per Un-served kWh	$2,401.0	$556.3	$373.1	$307.3	$271.7
Cost Per Annual kWh	$2.28E-02	$3.18E-02	$4.26E-02	$0.1403	$0.2482
Residential					
Cost Per Event	$2.7	$3.3	$3.9	$7.8	$10.7
Cost Per Average kW	$1.8	$2.2	$2.6	$5.1	$7.1
Cost Per Un-served kWh	$21.6	$4.4	$2.6	$1.3	$0.9
Cost Per Annual kWh	$2.06E-04	$2.48E-04	$2.94E-04	$5.81E-04	$8.05E-04

Table 4: Outage Costs by Customer Type and Duration (converted to 2012$)

Customer Type	Unit	Interruption Duration				
		Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I	Cost Per Event	$12,484	$16,682	$21,621	$62,853	$99,704
	Cost Per Average kW	$15.29	$20.50	$26.55	$77.10	$122.33
	Cost Per Un-served kWh	$183.82	$40.88	$26.55	$19.33	$15.29
Small C&I	Cost Per Event	$466	$648	$869	$2,863	$5,063
	Cost Per Average kW	$212	$295	$396	$1,305	$2,308
	Cost Per Un-served kWh	$2,549	$590	$396	$326	$288
Residential	Cost Per Event	$2.87	$3.50	$4.14	$8.28	$11.36
	Cost Per Average kW	$1.91	$2.34	$2.76	$5.42	$7.54
	Cost Per Un-served kWh	$22.94	$4.67	$2.76	$1.38	$0.96

Berkeley Study, p. xxi — CRA Study, p. 26

The important values used from this table are the various costs per un-served kWh (in $/un-served kWh) for the three customer classes. As noted by CRA, the CRA Study Table 4 contains different costs per kWh of un-served demand.[36] Consequently, it is important to match the actual duration of the event experienced by the customer class with the appropriate cost per

[31] Sullivan et al., *supra* note 11, at xxi.
[32] *Id.* at xx. The customer classes used in the Berkeley Study are: Large and Medium Commercial and Industrial; Small Commercial and Industrial; and, Residential.
[33] Plewes & Hieronymus, *supra* note 2, at 26.
[34] *Id.*
[35] Sullivan et al., *supra* note 11, at xxi, Table ES-1.
[36] Plewes & Hieronymus, *supra* note 2, at 26.

un-served kWh. To do this, CRA uses the before-mentioned approximately 3 hour outage,[37] found in their Table 3, but weights the distribution towards 30 and 40 minute events based upon a review of load shedding procedures of several retail electric providers (REPs) and the ERCOT load shedding event attributable to poor unit operations of February 2011.[38] A simple example of what CRA assumes is the average event is 3 hours long and for each of those 3 hours, 1,500 MW is curtailed. But the curtailment is rotated among different areas. There are six different groups, each curtailed for 30 minutes, and each group loses 1,500 MW of power for that 30 minutes. Therefore, the cost per un-served kWh used by CRA in their study is weighted to the 30 minute duration value found in their table, even though the total event time is approximately 3 hours. This methodology most accurately reflects ERCOT's procedures. I will address the significance of this briefly in the appendix, but for now I will continue with CRA's methodology. This weighting, based upon the methods employed by ERCOT and REPs, means the cost of un-served energy values used by CRA basically come from the 30 minute duration column of CRA Table 4, even though the event duration is close to 3 hours long.

STEP 3 OF THE CRA METHODOLOGY:

CRA now takes the values of cost per un-served energy from Table 4, weights them proportionately[39] and multiplies the dollar per un-served kWh (from Table 4) by the expected un-served energy value from Table 3.

CRA then models the Texas economy using an economic modeling tool, called REMI, which breaks the Texas economy down into 160 sectors and then determines the share of each sector represented by small and medium firms based upon US Census data employment figures. CRA then determines the proportional distribution of electricity consumption for small and medium firms, and this allows them to distribute the expected un-served energy from Table 3 across the 160 sectors. The net effect is that the 2014 value of 1310 MWh of un-served energy from Table 3 is multiplied by the proportionate cost, per sector from Table 4 of dollar per un-served kWh to determine a direct annual cost, found in Table 5.[40] Using the same proportions for the 160 sectors, the annual direct cost from Table 5 is then inserted into the REMI model, along with electricity costs, to model the impact on the Texas economy. Examining the 2014 values from Table 5 of the CRA Study, the annual direct cost of $110 million is proportionately distributed over the 160 sectors of the REMI model which returns an annual impact to Texas' gross state product. It is this result that is then added up for each year to return the large comparative gross state product loss found in Figure 7 of the CRA Study.

[37] CRA references the LOL Study, yet the median load profile annual outage duration values from Table 18 (2014) and Table 19 (2016) at 15-16 show values between 1.8 and 2.2 hours.
[38] *Id.* at 26-27.
[39] *Id.* at 29-30.
[40] *Id.* at 30. While this is what CRA does in their study, I question the overriding assumption that CRA makes that the total cost will always directly impact the Texas economy. For instance, assume I want to get myself breakfast at a diner, but just as I arrive, the diner experiences a power outage. Consequently, I do not buy breakfast at that diner. That particular diner loses the sale of breakfast to me and incurs some other associated expenses with the power failure. However, I still buy breakfast, just from another diner. So my contribution to the Texas economy still occurs despite the power outage. This example points out that the survey results deal with the subjective loss to *only* that particular business entity, applying those numbers in their entirety into an impact on the economy is questionable.

Summary of an Analysis of the Data used by CRA

Data utilized: CRA's Table 4 uses data from the Berkeley Study Table ES-1 and carries those values forward to 2012.

Error 1: Berkeley Study Table ES-1 is only for summer weekday afternoon values (see the title to Table ES-1 above). CRA uses this data as the primary input for dollar per un-served kWh. The effect of using data from the summer weekday afternoon period is that it imputes summer weekday afternoon usage throughout the course of the year, 24 hours per day. The CRA Study fails to incorporate data from other times of the day, week and year, *creating a highly inflated value of actual, overall cost of use*. Comparison with Table ES-4 (summer weekday) of the Berkeley Study shows that other time periods of the day are significantly less, particularly for the small commercial and industrial sector. For example, the cost per event value used by CRA throughout was $610 per event. The evening value of $299 per event, found in Table ES-4, is less than half the afternoon period.

The summer weekday afternoon period is the highest valued period in the Berkeley study and it is the highest use period in Texas. To arrive at a more accurate figure the CRA Study should incorporate electricity use periods from all times of the day in all four seasons.

Table ES- 4. Estimated Average Electric Customer Interruption Costs Per Event US 2008$ by Customer Type, Duration and Time of Day

	Interruption Duration				
Interruption Cost	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I					
Morning	$8,133	$11,035	$14,488	$43,954	$70,190
Afternoon	$11,756	$15,709	$20,360	$59,188	$93,890
Evening	$9,276	$12,844	$17,162	$55,278	$89,145
Small C&I					
Morning	$346	$492	$673	$2,389	$4,348
Afternoon	$439	$610	$818	$2,696	$4,768
Evening	$199	$299	$431	$1,881	$3,734
Residential					
Morning	$3.7	$4.4	$5.2	$9.9	$13.6
Afternoon	$2.7	$3.3	$3.9	$7.8	$10.7
Evening	$2.4	$3.0	$3.7	$8.4	$11.9

Berkeley Study for summer weekdays

All of the above errors are a result of CRA ignoring or overlooking the warning found on page xxv of the Berkeley Study: "*That is, it is not appropriate to just pick one of the interruption costs (for a specific season, day of the week and onset time of day)*."[41] Although the Berkeley Study warned readers of this effect, the CRA Study neither heeded nor reproduced the disclaimer.

Error 2: *CRA uses a value for the reserve margin in 2016 of 8.4% for the energy-only market construct.* They reference the CDR which shows a reserve margin of 10.4%. Had they

[41] Sullivan et al., *supra* note 11, at xxv (emphasis added).

used 10.4% (which is low to begin with as the CDR always projects a lower than actual reserve margin 3 – 5 years in the future)[42], *the resulting value of expected un-served energy in CRA Table 3 would have been about 7,108 MWh instead of the 15,311 MWh they actually used.*[43] This error more than doubles the un-served energy total and consequently more than doubles the direct cost they calculate from 2016 onward, and also impacts their 2015 calculations as they interpolate between 2016 and 2014 for that year. Calculation of their mistake is included in the appendix. To briefly summarize these errors, they determine reserve margin by dividing by generating capacity instead of load, and they inflate both generation and load by the same amount, resulting in an overall reduction in reserve margin of about 2%. Using 8.4% in 2016, CRA references the LOL Study (reproduced below).

Table 27. 2016 Annual EUE Results by Deficit Level (Weighted Load Profile)

Gen Capacity (MW)	Reserve Margin	Annual EUE for Various Capacity Deficiency Levels (MW)							
		All MW	<2700 MW	<2200 MW	<1700 MW	<1200 MW	<700 MW	<200 MW	<0 MW
82,660	5.8%	46,860.9	22,362.5	17,368.7	12,084.1	6,976.9	2,753.5	257.6	0.0
84,732	8.4%	15,311.3	7,676.3	6,125.2	4,424.1	2,646.2	1,091.3	109.5	0.0
86,809	11.0%	4,646.9	2,537.1	1,980.2	1,390.1	823.0	339.8	33.0	0.0
88,810	13.5%	1,279.8	849.2	693.1	507.5	308.0	130.9	12.4	0.0
90,810	16.0%	274.3	208.1	176.8	135.2	83.9	38.0	4.1	0.0
92,810	18.5%	45.1	38.3	32.1	25.5	16.4	7.5	1.1	0.0
94,810	21.0%	5.7	5.3	4.9	3.9	2.9	1.6	0.1	0.0
96,810	23.4%	0.4	0.4	0.4	0.4	0.3	0.1	0.0	0.0
98,332	25.3%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
100,770	28.4%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Error 3: *The Berkeley Study uses average annual electricity used to calculate the dollar per un-served kWh which artificially inflates the dollar value assigned to the cost per un-served kWh.* The Berkeley Study explains that because load profile data was not available for the customer types, they must use the annual average consumption in their calculations which, "oversimplifies the estimation of un-served kWh."[44] Because the cost per un-served kWh is determined by *dividing* the cost per event by the rate of consumption, if the actual rate of consumption is higher than the annual average, then the resulting dollar per un-served kWh will be lower than that calculated by Berkeley and incorporated by CRA. For example, summer afternoon power usage is considerably higher than the annual average power usage. Because dollar per un-served kWh is computed by dividing the estimated cost per event by the power usage, the resulting value for the summer weekday afternoon 30 minute duration would be much lower in the Berkeley table. The CRA table comes directly from the Berkeley table, only adjusted for 2012 values. Looking at a reasonable estimate of load distribution in the appendix, the actual load in the afternoon and evenings would be 40% higher, and since we're dividing by the number, the resulting dollar per un-served kWh would be 40% lower. *In the Berkeley Study table below, the small commercial and industrial consumer 30 minute duration would be reduced from $556.3 per un-served kWh to $333.8 per un-served kWh and there would likewise*

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42 *Supra*, note 20.
43 ECCO International Inc., *supra* note 8, at 21, Table 27.
44 Sullivan et al., *supra* note 11, at xxi.

be a 40% reduction in the CRA table value of $590 per un-served kWh to $354 per un-served kWh.

Table ES- 1. Estimated Average Electric Customer Interruption Costs US 2008$ by Customer Type and Duration (Summer Weekday Afternoon)

Interruption Cost	Interruption Duration				
	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I					
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Cost Per Annual kWh	$1.65E-03	$2.20E-03	$2.85E-03	$8.29E-03	$1.31E-02
Small C&I					
Cost Per Event	$439	$610	$818	$2,696	$4,768
Cost Per Average kW	$200.1	$278.1	$373.1	$1,229.2	$2,173.8
Cost Per Un-served kWh	$2,401.0	$556.3	$373.1	$307.3	$271.7
Cost Per Annual kWh	$2.28E-02	$3.18E-02	$4.26E-02	$0.1403	$0.2482
Residential					
Cost Per Event	$2.7	$3.3	$3.9	$7.8	$10.7
Cost Per Average kW	$1.8	$2.2	$2.6	$5.1	$7.1
Cost Per Un-served kWh	$21.6	$4.4	$2.6	$1.3	$0.9
Cost Per Annual kWh	$2.06E-04	$2.48E-04	$2.94E-04	$5.81E-04	$8.05E-04

Berkeley Study, p. xxi

Table 4: Outage Costs by Customer Type and Duration (converted to 2012$)

Customer Type	Unit	Interruption Duration				
		Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I	Cost Per Event	$12,484	$16,682	$21,621	$62,853	$99,704
	Cost Per Average kW	$15.29	$20.50	$26.55	$77.10	$122.33
	Cost Per Un-served kWh	$183.82	$40.88	$26.55	$19.33	$15.29
Small C&I	Cost Per Event	$466	$648	$869	$2,863	$5,063
	Cost Per Average kW	$212	$295	$396	$1,305	$2,308
	Cost Per Un-served kWh	$2,549	$590	$396	$326	$288
Residential	Cost Per Event	$2.87	$3.50	$4.14	$8.28	$11.36
	Cost Per Average kW	$1.91	$2.34	$2.76	$5.42	$7.54
	Cost Per Un-served kWh	$22.94	$4.67	$2.76	$1.38	$0.96

CRA Study, p. 26

Table ES- 4. Estimated Average Electric Customer Interruption Costs Per Event US 2008$ by Customer Type, Duration and Time of Day

Interruption Cost	Interruption Duration				
	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I					
Morning	$8,133	$11,035	$14,488	$43,954	$70,190
Afternoon	$11,756	$15,709	$20,360	$59,188	$93,890
Evening	$9,276	$12,844	$17,162	$55,278	$89,145
Small C&I					
Morning	$346	$492	$673	$2,389	$4,348
Afternoon	$439	$610	$818	$2,696	$4,768
Evening	$199	$299	$431	$1,881	$3,734
Residential					
Morning	$3.7	$4.4	$5.2	$9.9	$13.6
Afternoon	$2.7	$3.3	$3.9	$7.8	$10.7
Evening	$2.4	$3.0	$3.7	$8.4	$11.9

Summary: *Errors 1 & 3 above each greatly overstate the dollar per un-served kWh. Error 2 grossly overstates the amount of un-served energy and all three exacerbate one another because the values are multiplied together to produce an overall cost in dollars.* The CRA Study errors compound in the aggregate by the factor attributable to each input error. An example: Recall CRA, to begin with, only used summer weekday afternoon values from the Berkeley Study. Because CRA only used summer weekday afternoon values, here I refer to Table ES-4 from the Berkeley Study. In the evening CRA should have used $299 instead of $610. This would result in a correction factor of 299/610, but CRA also did not consider the load profile of the evening as identified by Berkeley. The load profile error would result in a 60% value, or now there are two corrections that have to be applied to the value CRA used, 299/610 x (0.6). The summertime vs. average correction is probably about 85.7%. So now there are three corrections, and the number used should be corrected by 299/610 x (0.6) x (.857). Finally, a fourth correction attributable to CRA's use of an 8.4% reserve margin must be applied. This fourth correction is at the very least equal to 7,108/15,331 or 46.4 %. Remember, this correction should actually be a smaller percentage as the CDR historically projects low reserve margins. Thus the fourth and final correction results in the following correction term: 299/610 x

(0.6) x (.857) x (.464) = 0.117. Since they used a value of $590 per un-served kWh (the summer afternoon value only) for all time periods throughout the year, the evening period value would have to be multiplied by 0.117 to be correct for the summer weekday evenings. The actual number of direct cost should have been less than 11.7% of the value they used for summer weekday evenings (remember 10.4% is a low projected reserve margin from the CDR). Every single time period of the year would require some form of correction factor.

An example of just how exaggerated the CRA Study is can be found by examining Tables 3 and 5 of the CRA Study, located on page 25 and 30 of the CRA Study and reproduced below. Examination of Table 5 for 2014 shows an annual direct cost of $110 million/yr. Referring to Table 3 of the CRA Study for 2014, Table 3 shows an event of 1,350 MW load lost, 2.4 hours per event and 0.4 events per year. Multiplying these numbers together produces 1,350 x 2.4 x 0.4 = 1,296 MWh per year of expected un-served energy for 2014. To obtain the $110 million/yr direct cost for 2014, CRA must perform the following calculation using the cost per un-served kWh ($EUE):

Table 3: Frequency, Duration and Size of Reliability Events from Relied Upon Studies

		ERCOT LOL Study			ERCOT RA Study	
		2014	2016		Average Year	2011 Weather
Reserve Margin	*%*	*13.0%*	*8.4%*	*13.5%*		
Loss of Load Events	# of events	0.4	3.7	0.4	0.9	12.4
Loss of Load Hours	# of hours	0.98	9.6	1.0	2.3	34
Average Outage Duration	Hours/event	2.4	2.6	2.4	2.6	2.7
Expected Unserved Energy (EUE)	MWh	1,310	15,311	1,280	3,450	85,000
	MW/event	1,350	1,598	1,280	1,500	2,500

Table 5: Annual and Per Event Outage Costs to Texas Economy

		2014	2016		Average Year		2011 Weather	
Scenario		Both	Energy Only	Energy + Capacity	Energy Only	Energy + Capacity	Energy Only	Energy + Capacity
Loss of Load Events	# of events	0.4	3.7	0.4	0.9	0.1	12.4	1.4
Annual Direct Cost	$ million	110	1,200	108	274	25	6,300	570
Direct Cost per Average Event	$ million	274	324	260	305	250	507	405

annual direct cost ($/yr) = $EUE($/MWh) x amount of load lost(MWh/yr)

Substituting the numbers for 2014:

$110 million/yr = $EUE x 1,296 MWh/yr

$EUE = ($110 million/yr)/1,296 MWh/yr = $84,876/MWh = $84.88 per un-served kWh.

For the sake of simplicity, the CRA Study uses an *average* dollar per un-served MWh for every person's and business' use of electricity in the State of Texas of $85,000 per MWh. In 2012, the ERCOT total energy use was 324.859 million MWh.[45] Carrying this example one step further, this implies that the Texas gross state product (in ERCOT region) should be $85,000/MWh x 324.859 million MWh = $27.6 trillion. In 2012, the Texas gross state product was $1.4 trillion.[46] Since ERCOT is only 85% of the Texas total electricity usage, the Texas ERCOT gross state product is $1.4 trillion x 0.85, or $1.19 trillion. *Based only on errors 1 and 3 above, the CRA Study is 23.2 times too high in its value of dollar per un-served kWh (27.6/1.2). Error 3, the error attributable to the amount of expected un-served energy is not included in the*

[45] ERCOT, 2012 energy use in ERCOT region down nearly 3 percent from 2011, http://ECCO International Inc.,.ercot.com/news/press_releases/show/26382

[46] Federal Reserve Bank of ST. Louis, FRED Economic Data, Total Gross Domestic Product by State For Texas (TXNGSP), http://research.stlouisfed.org/fred2/graph/?id=TXNGSP

23.2. Recall that error 3 was a minimum of 7,108/15,331 or 46.4%. *This means that the CRA Study errs in its determination of the cost of the energy-only market by 23.2/0.464 or a factor of 49.98.*

The CRA value grossly overstates the direct cost per event, by misusing three different studies. CRA takes a forward projected 2016 reserve margin value of 10.4% from the CDR, calls it 8.4% after making mathematical errors and uses it to return a highly inflated value of equivalent un-served energy from the LOL Study. They then ignore warnings by the Berkeley authors and only use the summer weekday afternoon value of dollar per kWh for every time period throughout the year. They compound this particular mistake by ignoring another warning from the Berkeley authors, and applying only the average annual load, not a realistic load profile to their already inflated value. These two inflated numbers are then multiplied together to produce the value of direct cost that CRA then inserts into the REMI model to compute the impact on Texas' gross state product. *It is these types of errors and omissions that the Berkeley Study warns against throughout.* The Berkeley Study identifies the assumptions they had to make, warns the diligent reader of them, and presumes a thoughtful and competent application of its results and analysis will be performed by anyone extending Berkeley's work. CRA, however, overlooks or disregards these disclaimers, thereby generating inflated figures to represent the costs associated with electricity interruption events.

PART 3: APPENDIX

This appendix consists of three sections:

Section 1 of the appendix examines how the Berkeley Study determines cost per un-served kWh. It also points out errors made by CRA in their study by failing to heed the warnings of the Berkeley Study and demonstrates with a few examples of how much of an impact those errors will cause in computing the direct cost of an electricity interruption event.

Section 2 of the appendix demonstrates the errors made by CRA in deciding that a 10.4% reserve margin in the CDR corresponds to an 8.4% reserve margin in the LOL Study. The magnitude of those errors on the value of direct cost is also demonstrated in this section.

Section 3 of the appendix covers other areas that touch on resource adequacy that surfaced in my review of the CRA and Berkeley Studies and that I feel should be very briefly examined and laid out on the table and perhaps considered in the future. These are not positions that I am advocating. They are issues that deserve some thoughtful examination by as many people as possible to determine if the issue has any merit, or if it belongs in the recycle bin.

Section 1: ERRORS IN COMPUTING COST PER UN-SERVED KWH

For simplicity I will refer you to Table ES-1 of the Berkeley Study on page xxi. It is important to note as discussed that the values in this table are only applicable to summer weekday afternoons.

The Berkeley Study begins by determining a cost per event.

Cost per Event: Determined from customer damage functions. The customer damage functions were created by analyzing many different survey results of electricity consumers from around the country, conducted by many different entities (primarily generating companies), across decades. The customer damage functions provide estimates of the costs of interruptions. Cost per event is determined for varying parameters. The parameters are: duration of loss of power (in hours or fractions thereof), day of the week (weekends or weekdays), different times during the day (morning, afternoon and evening), and season (summer and winter).

Again, please refer to Table ES-1 (reproduced below) and keep in mind that this table is only for summer weekday afternoons.

The unit for cost per event is: $/event

Table ES- 1. Estimated Average Electric Customer Interruption Costs US 2008$ by Customer Type and Duration (Summer Weekday Afternoon)

Interruption Cost	Interruption Duration: Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I					
Cost Per Event	$11,756	$15,709	$20,360	$59,188	$93,890
Cost Per Average kW	$14.4	$19.3	$25.0	$72.6	$115.2
Cost Per Un-served kWh	$173.1	$38.5	$25.0	$18.2	$14.4
Cost Per Annual kWh	$1.65E-03	$2.20E-03	$2.85E-03	$8.29E-03	$1.31E-02
Small C&I					
Cost Per Event	$439	$610	$818	$2,696	$4,768
Cost Per Average kW	$200.1	$278.1	$373.1	$1,229.2	$2,173.8
Cost Per Un-served kWh	$2,401.0	$556.3	$373.1	$307.3	$271.7
Cost Per Annual kWh	$2.28E-02	$3.18E-02	$4.26E-02	$0.1403	$0.2482
Residential					
Cost Per Event	$2.7	$3.3	$3.9	$7.8	$10.7
Cost Per Average kW	$1.8	$2.2	$2.6	$5.1	$7.1
Cost Per Un-served kWh	$21.6	$4.4	$2.6	$1.3	$0.9
Cost Per Annual kWh	$2.06E-04	$2.48E-04	$2.94E-04	$5.81E-04	$8.05E-04

This cost per event is then used to calculate a Cost per un-served kWh. To convert from $/event to $/kWh, the following conversion occurs:

The example below utilizes the momentary, or 5 minutes or less event for a <u>residence</u>.

$\$/kWh = \$/event\ (5min/event)^{-1}(60min/hr)(8{,}760hr/year)(total\ \underline{home}\ kWh/year)^{-1}$

The Berkeley Study uses an average home consumption of 13,351 kWh/year (page xxii and below). If we take the residential value of the <u>momentary</u> (momentary is defined as 5 minutes or less) cost per event from Table ES-1 (page xxi) of $2.74 and apply these two values to the above equation, we get:

$\$/kWh = (\$2.74/event)(5min/event)^{-1}(60min/hr)(8{,}760hr/year)(13{,}351kWh/year)^{-1}$

$\$/kWh = (\$2.74/event)(5min/event)^{-1}(60min/hr)(1.524kW)^{-1}$

= $21.6 per un-served kWh and this checks with the value found in Table ES-1

Sector	Annual kWh
Medium and Large C&I	7,140,501
Small C&I	19,214
Residential	13,351

The Berkeley Study describes that the average consumption is used (13,351 kWh/year for our example of residential customers) because there were no load profiles available for different time periods, days of the week and seasons. Consequently, just the average kWh/year is utilized. This introduces a significant error in the calculation of cost of un-served energy. It is important to note that kWh/year is just an average amount of power, applied to the consumer, for every second of the year. 13,351 kWh/year corresponds to a constant power draw of 1.524 kW. This assumption is the same as assuming that the electricity use of the household is fifteen, 100 watt light-bulbs turned on, and left on continuously for every hour of every day of the year.

The time periods utilized by the Berkeley study are:

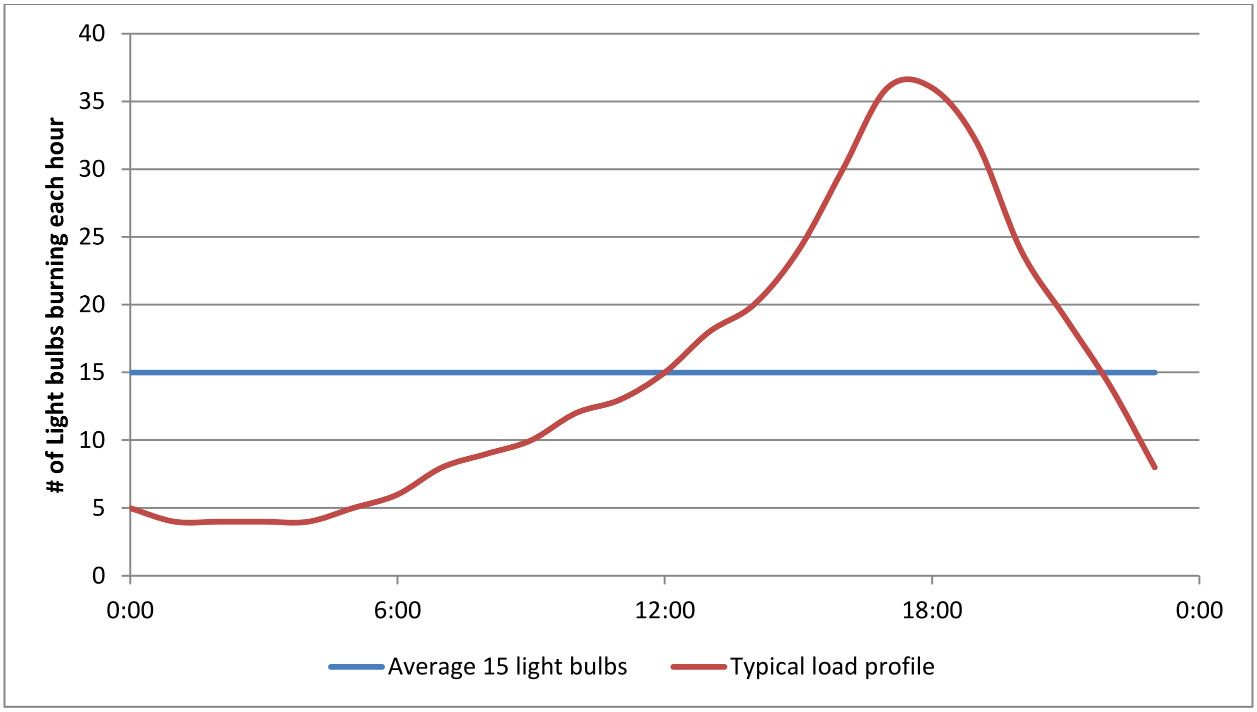
0600 – 1200 = morning

1200 – 1700 = afternoon

1700 – 2200 = evening

2200 – 0600 = night

If the load distribution is not a constant 1.524 kW then the values returned for un-served kWh will be different from that returned by the Berkeley study. Of significance, if the load drawn by a household is greater than 1.524 kW during the morning, afternoon, and evening, then the values returned from the Berkeley study will be proportionately less. As an example, let us suppose that our hypothetical family is the Simpsons, and their only electricity use is 100 watt light bulbs. For our example, the smallest increment of time we'll examine will be an hour. The Simpsons are an average family, that is they use on average, 15 light bulbs an hour, every hour. But they are different, in that they have 24 sets of 15 light bulbs. Each hour a different set of light bulbs is turned on, and the ones from the previous hour are turned off. That means that the Simpsons have 24 x 15 light bulbs, or 360 light bulbs, each that burn for 1 hour during the day. The load profile of the Simpsons based upon the Berkeley study is shown by the horizontal line in the graph below. A more typical (but estimated) load profile is shown on the same graph in red. In the estimated typical load profile, the same 360 light bulbs are burned for one hour each. But at midnight, only 5 are burning, at 6p.m., 36 are burning. Over the course of the day, the estimated typical load profile burns each bulb for one hour, the exact same amount of power consumed under the flat, or average profile used by the researchers in the Berkeley study.



Typical Estimated Load Profile (used in graph above)

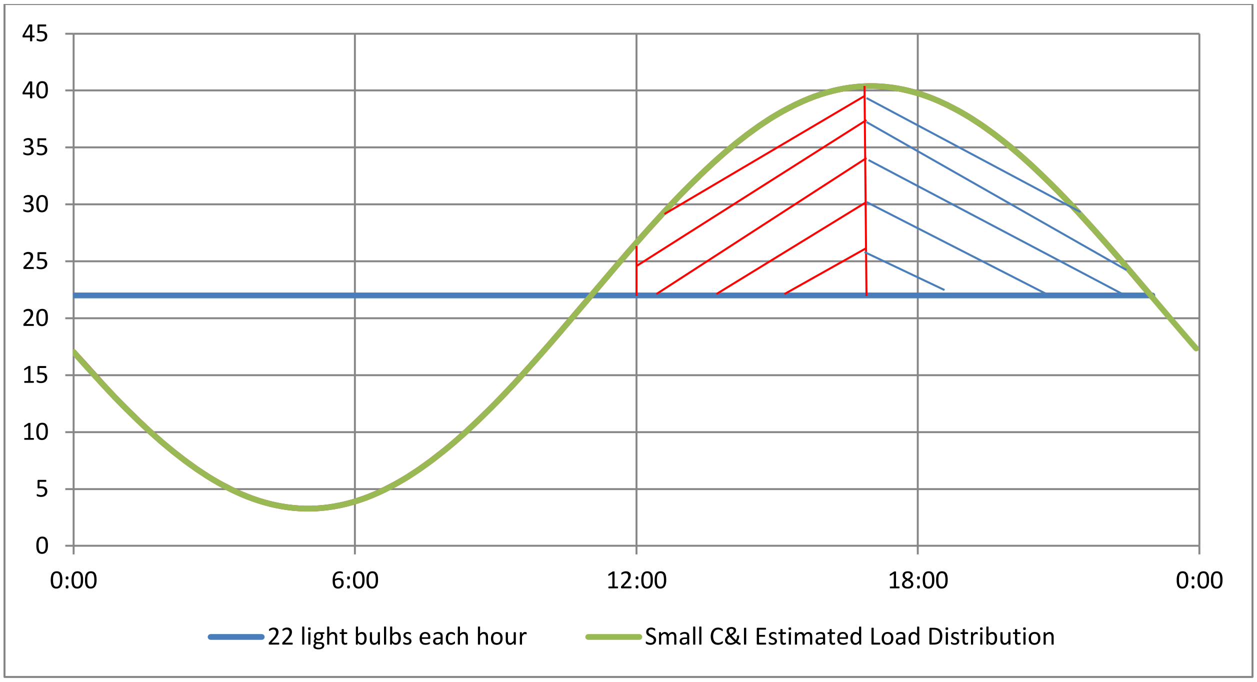
Time	0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00
light bulbs	5	4	4	4	4	5	6	8	9	10	12	13	15	18	20	24	30	36	36	32	24	19	14	8

This load profile burns the same 360 light bulbs, but not 15 each hour.

The effect of this profile is significant on the results obtained by the Berkeley study. On the basis of this load profile, which is only an estimate of a typical load profile, subject to the limits of my knowledge and guesswork, the cost of un-served load returned for the afternoon period is only 58.6% of that determined by Berkeley and the cost of un-served load returned for the evening period is only 60% of that determined by Berkeley. This is because the user valued his use in the afternoon at \$2.70. So he thought he was buying 128 light bulbs for \$2.70. The Berkeley Study had to assume he was only getting 75 light bulbs for \$2.70. Consequently, the Berkeley Study returns a higher cost per light bulb than the consumer has said he is actually willing to pay from the above profile. In my estimated load profile, the value for the morning period will be 134% of that used by Berkeley.

The Berkeley Study also assumes that the load profile is constant throughout the year. It is more reasonable to assume that the summer profile will be greater than the winter profile. If we divide the year in half and guess that summer usage is 40% higher than winter usage (at least in Texas), then in the summer months there would be 420 light bulbs in the Simpsons house, compared to only 300 in the winter months. If the bulbs were uniformly distributed across the estimated typical profile, then the cost of un-served load calculated by the studies is further reduced by the ratio of 360/420 or 85.7%. This would change the cost of un-served load in the summer months to 50.2% for the afternoon period and 51.4% for the evening period.

Now, looking at a pure sinusoid to describe the typical load profile, and shifting to numbers associated with Small C&I users. The same analogy to light bulbs is graphed here, only for Small C&I consumers, who average 2,200 watts constant power draw.



This particular graph assumes that peak will be 185% of the average and that the minimum will be 15%. The below values show the correction for the various time periods used as a function of the amplitude of the load profile. As you can see, the correction factors for the afternoon and evenings will likely be between 60% and 65%. The percentages in the table show the percent of the average value the minimum of the curve represents.

	10%	15%	20%	25%	30%
Correction factor from 1200 - 1700	60.09%	61.45%	62.88%	64.37%	65.94%
Correction factor from 1700 - 2200	60.09%	61.45%	62.88%	64.37%	65.94%
Correction factor from 0600 - 1200	168.11%	161.98%	156.28%	150.97%	146.01%
Correction factor from 2200 - 0600	211.10%	198.83%	187.91%	178.12%	169.30%

The above curve is drawn from the Berkeley Study Small C&I rates of electricity usage found on page xxii and reproduced above. The average value turns out to be about a constant power draw of 2,200 watts, or 22, 100 watt light bulbs. Applying a typical sinusoidal distribution to the usage produces extra power draw during the time period of 12 until 5 pm. The

Berkeley Study divides the cost per event by only the average amount – i.e., 22 light bulbs times the time period. Instead, the Berkeley Study should divide by the average of the 22 light bulbs times the time period, plus the red crossed area in the graph above. With just this correction, the dollar per un-served kWh in the Berkeley study is reduced by approximately 40%. From Table ES-1 the 30 minute value would change from $610 to $366 (and all numbers in the table would be reduced by 40%). Additionally, because Table ES-1 of the Berkeley study is only for "Summer Weekday Afternoons", it is likely that some other correction, such as that described in the paragraph above this curve, is also appropriate. Following the difference in distribution between summer and winter estimated above, the same correction factor of 85.7% would be obtained. Therefore, the $366 would be reduced to 85.7% of $366 or $313.66. This is again now 313.66/610 or only 51.4% of the Berkeley table value. The same is true for the evening time period. Recall that Berkeley sets the evening time period from 5pm until 10pm. Because the peak is modeled at 5pm, the load distribution is the same for the 5 hours after the peak as before the peak. So the overall electricity use from 5pm until 10pm is the same as from 12pm until 5pm. The 5pm until 10pm extra use, (not included by Berkeley in their calculations for dollar per un-served kWh) is shown by the blue cross hatched area under the curve. Consequently, the evening hours dollar per un-served kWh is also about 40% high, and then would be further reduced to 85.7% of that value, netting 51.4% of $299 per un-served kWh, which is the Berkeley evening value (found in Table ES-4 on page xxv). It appears that CRA used only the weekday *afternoon* values. At least that's what they reference as being "key". If calculating correctly for *evening* summer afternoon (30 minute duration), the figure used by CRA should have been 610 (CRA value) x 299/610 (correction for using afternoon value) x 60% (correction for actual load distribution instead of average utilized by Berkeley) x 85.7% (correction for summer load profile against average load profile). This results in a value in the evening that CRA should have used to be 299/610 x 0.6 x .857 or only 25.2% of the number they used, an almost 75% reduction.

The ripple through effect from the REMI model used by CRA could magnify this mistake even more. If the power function was a square of the direct energy cost, then the miscalculation would be $(0.252)^2$ or about 1/16 of the actual value used. Said another way, if the ripple effect is to square the direct cost amount, then CRA was 16 times high in their estimate just from this error alone. It is unlikely that the effect is to square the direct cost. More likely the power function is on the order of 1.1 or so. This would yield a mistake of $(0.252)^{1.1}$ or a reduction from 25% to 21.8%, still significant.

Section 2: HOW CRA MAKES A 10.4% CDR VALUE EQUAL AN 8.4% LOL VALUE

Let me first begin with a disclaimer. I'm guessing here. The only things I have to go on are the actual reports, and a cryptic footnote in the CRA Study. Footnote 29 on page 24 of the

CRA Study reads, "13.8% in 2014 corresponds to the ERCOT LOL Study estimates for 13% RM. 10.4% in 2016 corresponds to ERCOT LOL Study estimates for 8.4% RM."[47]

One would think that when equating 10.4% to 8.4% this decision would warrant slightly more justification and explanation than that provided above, but that's all we have to work with. So here's the detective work:[48]

2013 Report on the Capacity, Demand, and Reserves in the ERCOT Region

Summer Summary

Load Forecast:	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Total Summer Peak Demand, MW	69,807	72,071	74,191	75,409	76,186	76,882	77,608	78,380	79,055	79,651
less LRS Serving as Responsive Reserve, MW	1,222	1,222	1,222	1,222	1,222	1,222	1,222	1,222	1,222	1,222
less LRS Serving as Non-Spinning Reserve, MW	0	0	0	0	0	0	0	0	0	0
less Emergency Response Service	475	523	575	632	696	765	842	926	1019	1121
less Energy Efficiency Programs (per Utilities Code Section 39.905 (b-4))	518	648	781	917	1054	1193	1210	1225	1238	1238
Firm Load Forecast, MW	**67,592**	**69,679**	**71,613**	**72,637**	**73,214**	**73,702**	**74,334**	**75,007**	**75,576**	**76,070**
Resources:	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Installed Capacity, MW	64,998	64,998	64,998	64,998	64,998	64,998	64,998	64,998	64,998	64,998
Capacity from Private Networks, MW	4,331	4,331	4,331	4,331	4,331	4,331	4,331	4,331	4,331	4,331
Effective Load-Carrying Capability (ELCC) of Wind Generation, MW	920	920	920	920	920	920	920	920	920	920
RMR Units to be under Contract, MW	0	0	0	0	0	0	0	0	0	0
Operational Generation, MW	**70,248**	**70,248**	**70,248**	**70,248**	**70,248**	**70,248**	**70,248**	**70,248**	**70,248**	**70,248**
50% of Non-Synchronous Ties, MW	628	628	628	628	628	628	628	628	628	628
Switchable Units, MW	2,977	2,977	2,977	2,977	2,977	2,977	2,977	2,977	2,977	2,977
Available Mothballed Generation, MW	618	722	590	430	246	167	167	167	167	167
Planned Units (not wind) with Signed IA and Air Permit, MW	2,927	3,497	4,881	6,261	6,261	6,261	6,261	6,261	6,261	6,261
ELCC of Planned Wind Units with Signed IA, MW	187	389	399	399	399	399	399	399	399	399
Total Resources, MW	**77,586**	**78,462**	**79,724**	**80,944**	**80,760**	**80,681**	**80,681**	**80,681**	**80,681**	**80,681**
less Switchable Units Unavailable to ERCOT, MW	-317	-317	-317	-317	-317	-317	-317	0	0	0
less Retiring Units, MW	-354	-354	-354	-354	-354	-1,199	-1,199	-1,199	-1,199	-1,199
Resources, MW	**76,915**	**77,791**	**79,053**	**80,273**	**80,089**	**79,165**	**79,165**	**79,482**	**79,482**	**79,482**
Reserve Margin	**13.8%**	**11.6%**	**10.4%**	**10.5%**	**9.4%**	**7.4%**	**6.5%**	**6.0%**	**5.2%**	**4.5%**
(Resources - Firm Load Forecast)/Firm Load Forecast										

1. The CDR for 2016 shows a reserve margin of 10.4%. The reserve capacity attributed to this is 7,440 MW (79,053 – 71,613 = 7,440).

[47] I've had an opportunity to discuss this section briefly with Jeff Plewes who confirmed the manner of conversion, albeit I did not go into details with him regarding the mistakes, I just confirmed my understanding of how CRA moved to different percentage values between the CDR and LOL Study.

[48] Now is a good time to give some credit. Jeff Plewes and Bill Hieronymus of CRA were very generous and made themselves available to spend time with me on the phone when I needed to verify my understanding of some of the CRA methodology. Josh Schellenberg, of Freeman, Sullivan & Co., who is one of the principal authors of the Berkeley Study did the same, including a few emails. The most important insight and assistance came from David Gordon, a colleague and Commissioner Kenneth W. Anderson's attorney advisor who was a terrific sounding board and contributed several very important points to this analysis, and none of the bad humor.

Table 27. 2016 Annual EUE Results by Deficit Level (Weighted Load Profile)

Gen Capacity (MW)	Reserve Margin	Annual EUE for Various Capacity Deficiency Levels (MW)							
		All MW	<2700 MW	<2200 MW	<1700 MW	<1200 MW	<700 MW	<200 MW	<0 MW
82,660	5.8%	46,860.9	22,362.5	17,368.7	12,084.1	6,976.9	2,753.5	257.6	0.0
84,732	8.4%	15,311.3	7,676.3	6,125.2	4,424.1	2,646.2	1,091.3	109.5	0.0
86,809	11.0%	4,646.9	2,537.1	1,980.2	1,390.1	823.0	339.8	33.0	0.0
88,810	13.5%	1,279.8	849.2	693.1	507.5	308.0	130.9	12.4	0.0
90,810	16.0%	274.3	208.1	176.8	135.2	83.9	38.0	4.1	0.0
92,810	18.5%	45.1	38.3	32.1	25.5	16.4	7.5	1.1	0.0
94,810	21.0%	5.7	5.3	4.9	3.9	2.9	1.6	0.1	0.0
96,810	23.4%	0.4	0.4	0.4	0.4	0.3	0.1	0.0	0.0
98,332	25.3%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
100,770	28.4%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

2. CRA then uses the LOL Study, table 27 reproduced above, and does something like this: 7,440/82,660 = 9%, nope that does not correspond to 5.8%. Let's try 7,440/84,732 = 8.8%, hey that's pretty close to 8.4%. Ok, now let's try 7,440/86,809 = 8.6% well, that's not close to 11%. Ok, then we'll pick 8.4% and say that the 10.4% CDR value corresponds to 8.4% in the LOL study, using the 7,440 reserve margin from the CDR and table 27 values from the LOL study. Consequently, CRA uses 15,311 MWh for the amount of un-served energy for an energy-only market for 2016. Note here, they are dividing by *the generating capacity* to find the match.

3. For a check, let's see how 2014 matches up with this logic, only in one step. But we have to look at the 2014 Table from the LOL Study, that's Table 26, reproduced below. 2014 reserve capacity is 76,915 – 67,592 = 9,323. 9,323/80,507 = 11.6% not close to 10.2%. How about 9,323/82,535 = 11.3% not close to 13%. But wait, CRA said the 2014 RM corresponded to 13%? Let's check to see if they divided by the load value, which would be the proper way to calculate reserve margin, but still introduces some errors (discussed later). Now the load from Table 26 is just the generating capacities minus 9,323. So for the first try, 9,323/(80,507-9,323) = 13.1% no, not close to 10.2%. How about 9,323/(82,535-9,323) = 12.7%, that's pretty close to 13%. Let's check the next one, 9,323/(84,535-93,23) = 12.1%, nope that's not close to 15.6%. So CRA says this: because 9,323/(82,535-9,323) = 12.7%, and that's pretty close to the reserve margin from the LOL Study table of 13% which corresponds to generating capacity of 82,535 then we can use the 13% reserve margin results from the LOL Study for 2014.

Table 26. 2014 Annual EUE Results by Deficit Level (Weighted Load Profile)

Gen Capacity (MW)	Reserve Margin	Annual EUE for Various Capacity Deficiency Levels (MW)							
		All MW	<2700 MW	<2200 MW	<1700 MW	<1200 MW	<700 MW	<200 MW	<0 MW
76,400	4.8%	62,435.0	32,093.9	24,775.3	16,935.7	9,540.0	3,670.1	335.8	0.0
78,471	7.5%	18,834.2	11,015.6	8,854.5	6,454.2	3,901.1	1,585.8	154.4	0.0
80,507	10.2%	4,969.8	2,875.2	2,352.3	1,738.9	1,104.5	477.1	50.7	0.0
82,535	13.0%	1,309.5	812.6	646.9	466.5	287.7	118.4	11.5	0.0
84,535	15.6%	307.9	230.8	193.5	144.1	90.9	37.7	3.9	0.0
86,535	18.3%	50.6	44.3	38.9	29.6	20.0	8.9	1.1	0.0
88,535	21.0%	5.1	5.0	4.4	4.1	2.9	1.4	0.2	0.0
90,535	23.6%	0.2	0.2	0.2	0.2	0.2	0.1	0.0	0.0
92,535	26.3%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
94,535	29.0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

4. Now you'll realize that for 2014, they divided by load to determine a reserve margin percentage (still introduces some errors). But for 2016, they divided instead by the generating capacity. This is not the correct way to determine reserve margin at all, and there are still other errors introduced the same as for 2014. They then carry these values, 8.4% for the energy-only market, and 13.5% for the energy plus capacity market for all years through 2028.

5. There are other errors introduced by CRA's conversion from the CDR to the LOL Study. The CDR shows maximum generating capacity for 2014 to be 76,915. But the generating capacity that CRA said is equivalent is 82,535. CRA uses the reserve margin value of 9,323 from the CDR, to presume a load value of 82,535 – 9,323 = 73,212. Recall that 9,323/73,212 = 12.7% and that the CDR value of reserve margin is 13.8%. Even though they use the same difference (9,323) from the CDR and apply it to the LOL Study, the percentage goes down from 13.8% to 12.7%. This is because CRA increases both generation and load by the same amount by performing this calculation. They've increased 2014 generating capacity from 76,915(CDR) to 82,535(LOL Study), a 5,620 MW increase. Correspondingly CRA increased load from 67,592 (CDR) to 73,212 (LOL Study), also a 5,620 MW increase. And CRA believes that this is fine, everything is equivalent because they left the underlying reserve margin (9,323) the same. At least for 2014 they divided by the load value, but here's the error introduced. The CDR says, 76,915/67,592 = 1.13793, or 13.8%. To get to the LOL Study, CRA does this, (76,915+5,620)/(67,592+5,620) = 1.12734 or 12.7%. What they've done is add 5,620 MW to both load and generation, for this incremental 5,620 MW increase a 0% reserve margin occurs. The weighted average of 0% for 5,620 and 13.8% for 67,592, is 12.7%. That's how they go from 13.8% in the CDR being equivalent to 12.7% in the LOL Study, but heck, let's just call it 13%.

6. For 2016, they repeat the exact same mistake, only they compound it by dividing not by the load, but by the generating capacity (as discussed above).

7. From the LOL Study results, CRA extracts a EUE value. Let's look at the impact. They assume 8.4% in 2016, that returns an EUE of 15,311 MWh. This then gets distributed across the 160 sectors, has the $ per un-served kWh applied to it, totaled up into a direct cost figure in CRA Study Table 3. But if you were to just take the CDR value from 2016, 10.4%, interpolate a value for EUE from the LOL Study, you would get, (10.4 – 8.4)/(11 – 8.4) x (4,646.9 – 15,311.3) + 15,311.3 = 7,107.9 MWh. At the very minimum, they inflate the EUE for the energy market construct from 7,108 MWh to 15,311 MWh, more than double. And this is if you use the 3 year forward projection that is historically low[49], of 10.4% reserve margin. They carry these mistakes all through their determination of EUE from 2016 until 2028.

8. It is not hard to see how the CRA Study numbers for the energy-only construct result in an extremely large direct cost. Exactly how large is almost impossible to determine precisely because of the need to perform assumptions (i.e., what will the actual reserve margin be in 2016?). In my estimation, the resulting direct cost is off by more than an order of magnitude, consistent with my gut reaction to the cost determined by CRA to be the same as that of a small, yet lethal, Texas submarine fleet.

Section 3: Other Areas That Warrant Consideration Based On the CRA and Berkeley Studies.

<u>How to determine dollar per un-served kWh</u>.

The Berkeley Study was required to use subjective survey results in order to determine a cost per un-served energy. There is another way to consider the reasonableness of the $85,000/MWh average dollar per un-served MWh used by CRA and at the same time remove the subjective nature of the Berkeley Study methodology by using actual accurately determined values. In 2012 the Texas GSP was $1.4 trillion.[50] In 2012 the total kilowatt hours consumed in ERCOT (representing 85% of the Texas total electricity usage) was 324.859 billion kWh.[51] Simple mathematics says $1.4 trillion/324.859 billion kWh x .85 = $3.66 per kWh ***on average*** at the retail level. That is how the Texas economy leverages electricity, we pay about 10¢/kWh at the retail level and produce ***on average*** $3.66/kWh of GSP. I believe this value, generated from two accurate values, more truly represents an *average* dollar per un-served kWh than the mistake laden $85,000/MWh computed by CRA from subjective survey results collected over decades by a variety of different generating companies across the country.[52] CRA ultimately used a value of $85/kWh, and then multiplied it by an artificially high number of un-served kWh (they assumed an 8.4% reserve margin for the energy-only market). That produces an error greater than an order of magnitude (actually about 50 times too high).

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[49] *Supra* note 20.
[50] Federal Reserve Bank of ST. Louis, *supra* note 46.
[51] ERCOT, *supra* note 45.
[52] This average value of $3.66/kWh ($3,660/MWh) includes residential customers. For comparison with a more rigorous and detailed study, *see* London Economics International LLC, *Estimating the Value of Lost Load*, June 17, 2013, Figure 38 at 61. The Texas sector-specific implied value of lost load for 2011 for commercial consumers was $6,979/MWh and for industrial consumers was $3,706/MWh.

As I've already pointed out there are numerous mistakes made in the CRA Study that have greatly inflated the CRA average value of un-served energy used of $85,000/MWh. But we should be very skeptical of using survey results to calculate a dollar per un-served kWh because of their subjective nature. What should be considered is the method used to determine $/kWh. The Berkeley Study identifies limitations with its study, but it seems to me that introducing survey results from individuals or entities creates a very large amount of subjective error. We know to a high degree of accuracy how much energy is consumed in a given year in ERCOT. We also have a pretty good idea of the value of Texas' GSP. Those two values return a reasonably exact value of dollar per un-served kWh. Maybe this straight-forward, accurate approach cannot be used, even though it uses very reliable numbers because we will not know what is the actual individual industry or business dollar per un-served kWh. Unless we plan on being selective in a load shedding event, it does not matter. This method, compared to the more arduous and certainly more subjective survey method, should be considered as an alternative approach for determining an average dollar per un-served kWh.

<u>What about the impact to the Texas economy caused by outages other than those caused by a load shedding event?</u>

It is generally well accepted that transmission and distribution outages caused by events such as bad weather and equipment failure subject Texas consumers of electricity to 100 times more loss of load than do outages caused by insufficient generation.[53] If you really accept the numbers in the CRA Study as true, then bad weather and equipment failure outages are $1.7 trillion over a 15 year period. That should give us much incentive to upgrade every aspect of our transmission and distribution grid. If you accept the CRA average dollar per un-served kWh of $85,000/MWh, investing the extra money in improving this aspect of the grid would pay off more handsomely than the cost it would take to get only 1% improvement available from generating reliability.

<u>If the economic equilibrium reserve margin is 9.2% why have we not equilibrated to it by now?</u>

The Brattle Group provided an analysis in June 2013 indicating that the energy-only market construct would reach an economic equilibrium reserve margin of 9.2%.[54] First of all, I want to make it perfectly clear that I'm not being critical of the Brattle Group's analysis. The economic modeling requires many assumptions and estimations and is very difficult to understand, comprehend and ultimately put together so that it generates a number. My background is engineering and part of that background consists of control theory. While our economic market construct is not an engineering system, once you start talking about equilibrium then the principles of system dynamic response are pretty much the same. An engineering system, whether electrical or mechanical when subjected to an impulse typically responds in one of three manners: Critically damped (which is usually ideal), over damped or under damped. Below I've included a graph as a visual example that shows the three manners of damping for harmonic oscillators.

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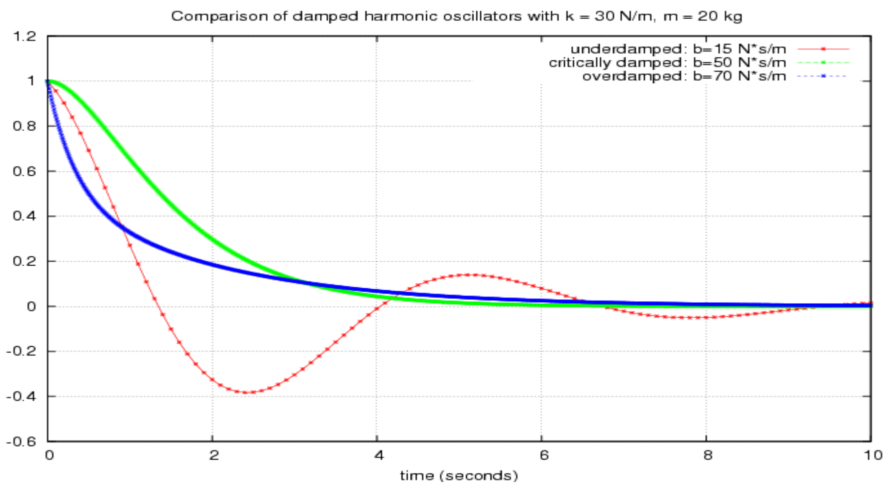
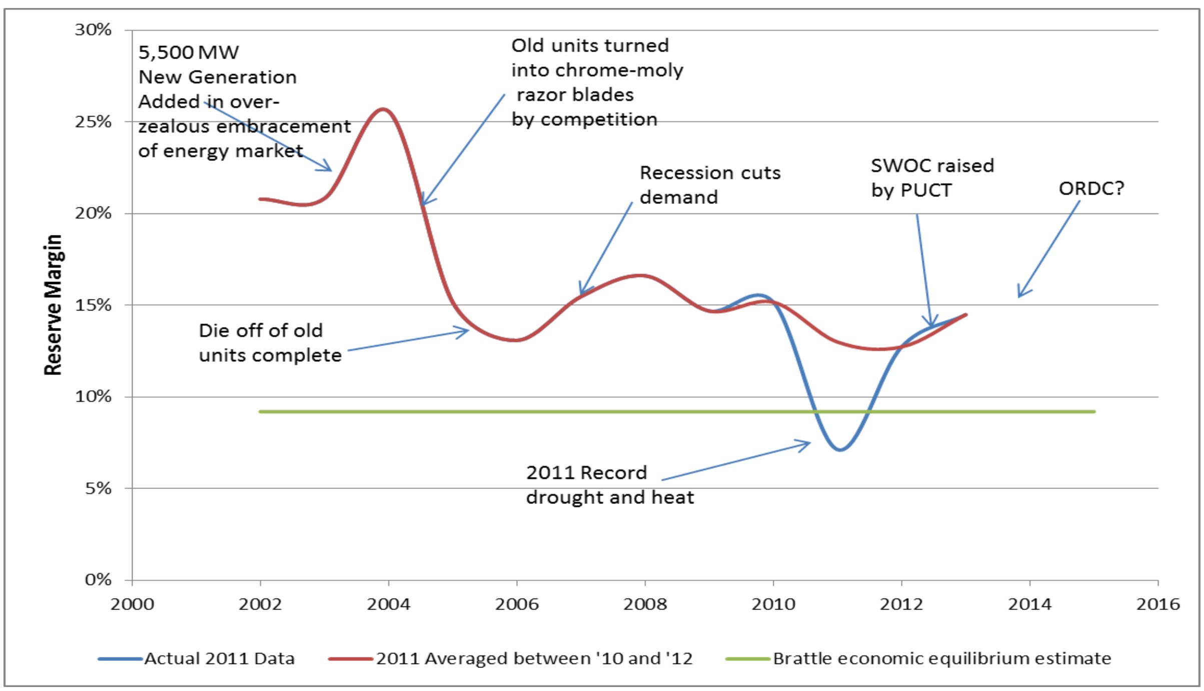
[53] Newell, *supra* note 9.
[54] Newell, *supra* note 30.



As you can see, the damped oscillators all reach equilibrium, but they get there at different times, and follow different paths. The longer it has been since the system response begins, the closer and closer the system gets to equilibrium, regardless of whether it is critically, under or over damped. So when the Brattle Group's model came out I thought it would be a good idea to look at ERCOT's history, from when our energy market construct began, and look at how our actual reserve margin has behaved. Here's the graph:



In this graph, I took the *peak*[55] demand in each year, subtracted it from the generating capacity, and then divided that value by the peak demand. The Brattle Group's 9.2% line is the

[55] *Supra* note 20 as well as predecessors to the ERCOT summer CDR before 2005. Note that I used the actual peak demand in each year. This returns a worst case actual reserve margin for the year. The CDR computed reserve margin is based upon firm load forecast, not peak load forecast. Because this graph is used to look at the system

horizontal green line. The red curve is the actual reserve margin we experienced each year, but with 2011 averaged between 2010 and 2012.[56] The blue line graphs actual 2011 data. On the graph I have tried to include events that I consider to be an impulse to our energy market system. Some may impulse the curve up, some may impulse it down. There may be other events out there that I am not aware of, but the curve is the actual data. The more time that has elapsed since the last impulse, and the smaller the magnitude of the impulse, the sooner we will reach equilibrium. Upon visual examination, I conclude that our system exhibits behavior similar to an under damped system. If we had 100 years of history, instead of 10, I would say we would never reach equilibrium at 9.2%, unless we impulse and change the system downward in a very strong manner. But we only have 10 years of history, so I suppose it is possible. But right now, the Commission is going out of its way to avoid impulsing the system downward. This tells me we're not going to reach 9.2% anytime soon.

How much more generation do we really need in an emergency, and is there a better, cheaper way to provide for it for all Texans?

One critical aspect of the LOL Study is when the loss of load events are most likely to occur. The LOL Study shows that about 95% of the predicted events are likely to occur in July and August and 1,500 MW would roughly be the amount curtailed.[57] Let's look at the cost of a capacity market using actual data from an existing centralized forward capacity market. The PJM Interconnection LLC (PJM)[58] is a centralized forward capacity market construct often referenced as a model for capacity markets. In 2012 capacity payments for the PJM Reliability Pricing Model (RPM) were \$6.02/MWh for the total MWh consumed in PJM.[59] In 2012 in ERCOT there were 324.859 million MWh total consumed.[60] Consequently at \$6.02/MWh capacity payment cost for a fully functional, up and running capacity market[61] ERCOT consumers would have had to pay 324.859 million MWh x \$6.02/MWh = \$1.956 billion *just for 2012*. ***In 2012 there were no load curtailments in ERCOT. \$1.956 billion a year seems like a rich insurance premium to me.*** When we look at an *annual* insurance payment of \$1.956 billion we need to ask ourselves *what are we getting for that premium that we do not have already?* If we believe the studies referenced by CRA and by the CRA Study itself, we only need the aforementioned 1,500 MW of insurance generation during a very limited time during the year.

response to impulses, and because it is historical, the actual worst case scenario for each year is examined. There is therefore no cushion in these numbers and yet we still are not approaching 9.2%, and even in 2011 only reached 73,175 MW capacity/68,305 MW peak demand, or 7.13% reserve margin.

[56] Because 2011 was such an extreme weather year I felt it appropriate to smooth that year to see how it would fit in with the system approaching equilibrium. The extreme weather of 2011 was, in effect, just an external downward impulse on the system that had no long term effect on the system itself. An example of an impulse to the system that changes the system and its response to an impulse is the increase of the system wide offer cap in 2012.

[57] ECCO, *supra* note 8, Tables 20 & 21, at 17.

[58] PJM is an electricity market that utilizes capacity payments as part of its structure very similar to the energy plus capacity market construct modeled in the CRA Study. PJM covers the mid-Atlantic states from New Jersey south through Virginia to a portion of North Carolina and extends west through Ohio into parts of Indiana, Illinois and Kentucky. A way to think of PJM is meaning, Pennsylvania, Jersey & Maryland but it extends beyond those states.

[59] PJM's Response to the 2012 State of the Market Report, May 10, 2013 at 2.

[60] ERCOT, *supra* note 45.

[61] PJM is a mature market. The start-up costs of beginning a capacity market construct are substantially over and above this \$1.956 billion annual cost.

Our existing energy market construct provides everything else as it exists today! Suppose instead of paying $1.956 billion per year ERCOT established a new reserve service as part of its ancillary services and procured through an auction process 1,500 MW of newly built generating capacity in the form of combustion turbines that was available only for the time periods we really needed it? 99.5% or more of the time it would sit idle. It would not compete with any of the other generation in the market and it would only be used as an emergency source. If we assume a very conservative value of $1 million per MW to construct[62], it would cost ERCOT consumers $1.5 billion. It would only need to be used for a few hours (if any) at most, in a year. This one-time cost of $1.5 billion is far less than an *annual* insurance premium of $1.956 billion[63] that a PJM style capacity market would impose on ERCOT rate payers. This 1,500 MW of generation would solve basically all of our resource adequacy problems. So ERCOT could build enough generation to solve this perceived problem and let it sit on the ground waiting to be needed for less than 1/10 the cost of a capacity market.[64]

The principle reason a capacity market cost is 10 times the cost of just building our own 1,500 MW of generation is because the capacity market construct involves required payments for extra electricity equal to the percentage of reserve margin that is made mandatory every hour of the day, every day of the year. This happens at the wholesale level. Let's assume that the Public Utility Commission of Texas makes the decision that a 15% reserve margin is mandatory. The extra 15% will be purchased in some manner (there are a variety of ways), and the money will be paid out to generators. No matter how that extra reserve margin is purchased, load serving entities (LSE) will be assessed the extra cost on a pro-rata basis of their actual load. This amount is over and above the amount that the LSE's customers actually use.[65] For instance, if a LSE has customers that would normally use 1 million MWh/month, that LSE has to contract with generators at the wholesale level to buy 1 million MWh in that month and then will be assessed a cost associated with an additional 15% or 150,000 MWh in that same month. Who ultimately pays the generators for that extra 15%? ***You do! The LSEs will pass that mandatory extra wholesale cost that they are assessed along to you! It will be added to your bill as an extra 15% assessment. If you use 1,000 kWh in the month, you will pay for that 1,000 kWh and then be assessed an additional charge amounting to another 150 kWh.*** This is how a capacity market "ensures" there is a reserve margin of 15%. This past summer our energy-only market construct provided a 13.75% reserve margin by itself with no extra cost passed on to you. In ERCOT's energy-only market, LSEs are not assessed an additional cost of the 13.75% above what their customers use, it is already available as needed by the nature of the energy-only

[62] Newell, *supra* note 9 Table 9 at 47 listing combustion turbine capital costs at $667.4/kW ($667,400/MW) and combined cycle capital costs at $798.2/kW ($798,200/MW).

[63] The net present value (NPV) of $1.956 billion for 30 years at various discount rates is shown here:

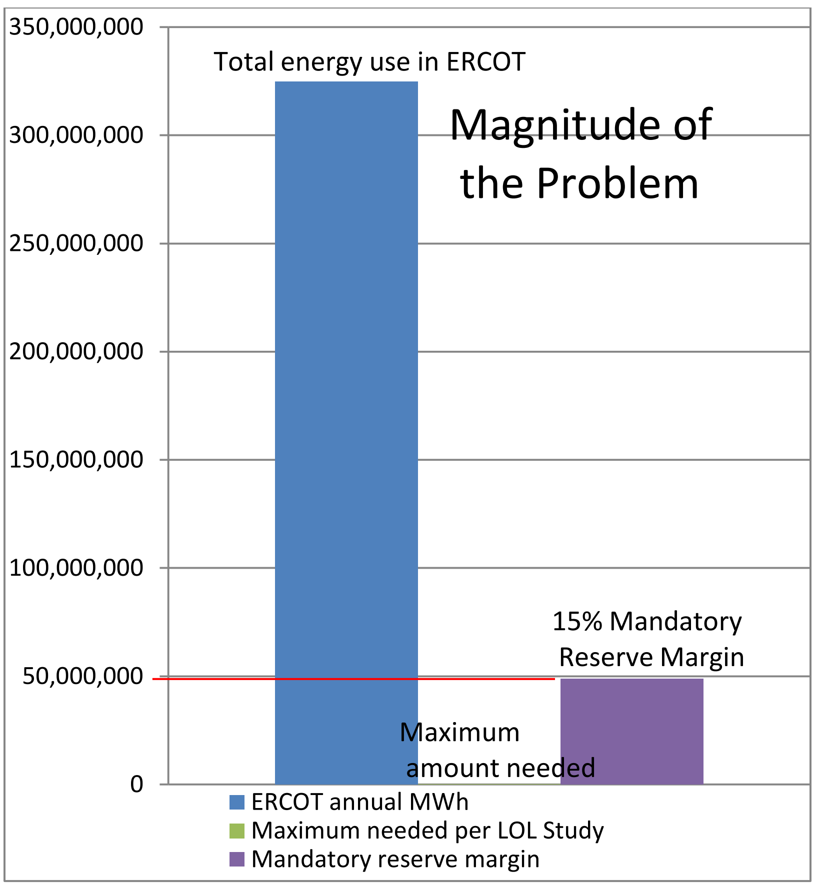
Discount Rate	3%	4%	5%	6%	7%
NPV of $1.956 billion	$38.34 billion	$33.82 billion	$30.07 billion	$26.92 billion	$24.27 billion

[64] There would of course be annual operating and maintenance expenses but they would be small compared to the annual cost of a PJM style capacity market.

[65] As I mention there are a variety of ways "capacity" can be purchased, however it is very important to understand that it is a payment for "energy" which is MWh. It is also important to understand that the capacity payment is paid to generators "**whether or not energy is produced by resource**." (emphasis added). *See, PJM Emergency DR (Load Management)*, November 14, 2013, at 5.
http://www.pjm.com/Calendar%20Events/PJM%20Calendars/Training%20Events/2013/November/19/~/media/77B6232F99EC4D0CA6B71D9F0A548C81.ashx

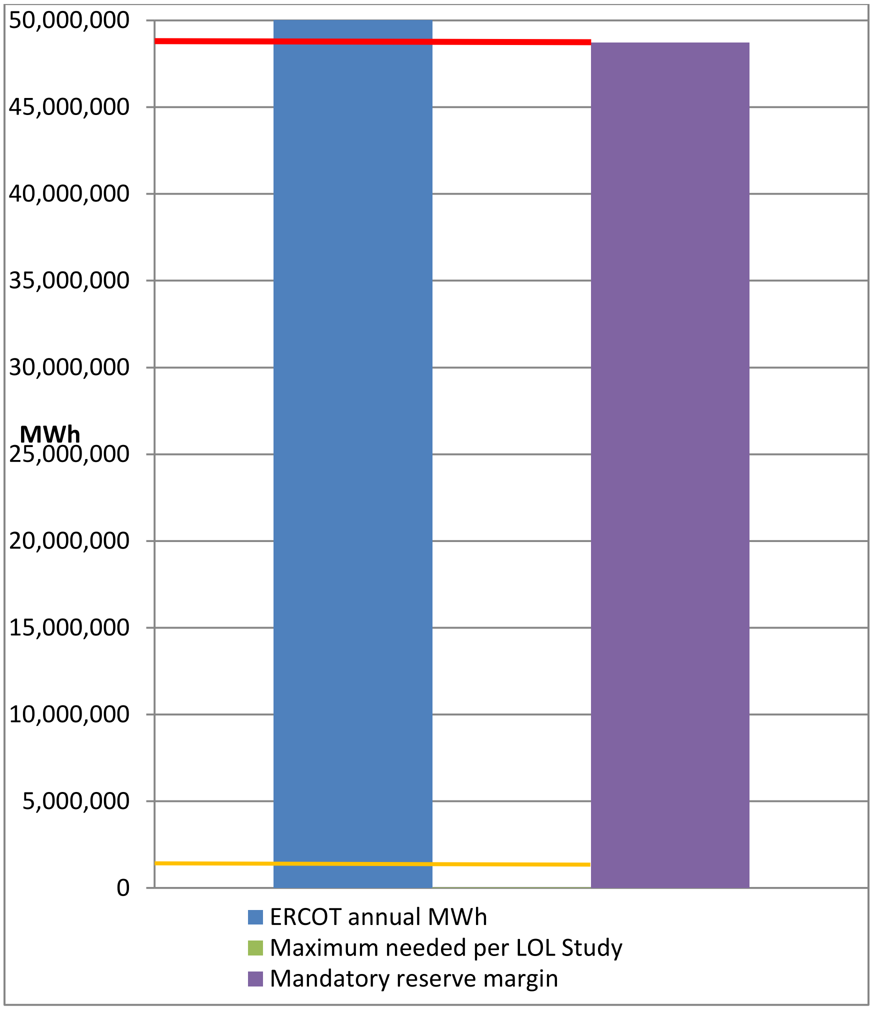
market. In the ERCOT market, if a 15% reserve margin is mandated, then a cost equaling an extra 15% of roughly 324.859 million MWh would be assessed against ERCOT Texans. **Please note: This is an extra charge equaling $6.02/MWh x 324.859 million MWh or $1.956 billion, it is *not* the purchase of extra electricity.[66]** The LOL Study indicates we only need 1,500 MW to cover any shortage of MWh and that the total un-served energy that needs to be covered (refer to the calculations above) is at most 7,108 MWh in 2016. Because our energy-only market provides all but this amount, ***we would be paying for approximately 48.73 million MWh more than we need each year.*** Consequently the CRA Study results tell me that it is more economical for ERCOT to procure three 500 MW newly built units before we shift to a capacity market at a cost of $1.956 billion per year.

Let's *try* to look at the size of the problem graphically. I say try, because when graphed to scale it is really hard to see. Here are three simple graphs that show the size of the problem that we are trying to solve by spending at least $1.956 billion dollar per year by instituting a capacity market construct. The following graphs are to scale, note the red line marking the top of the 15% mandatory reserve column in the first.

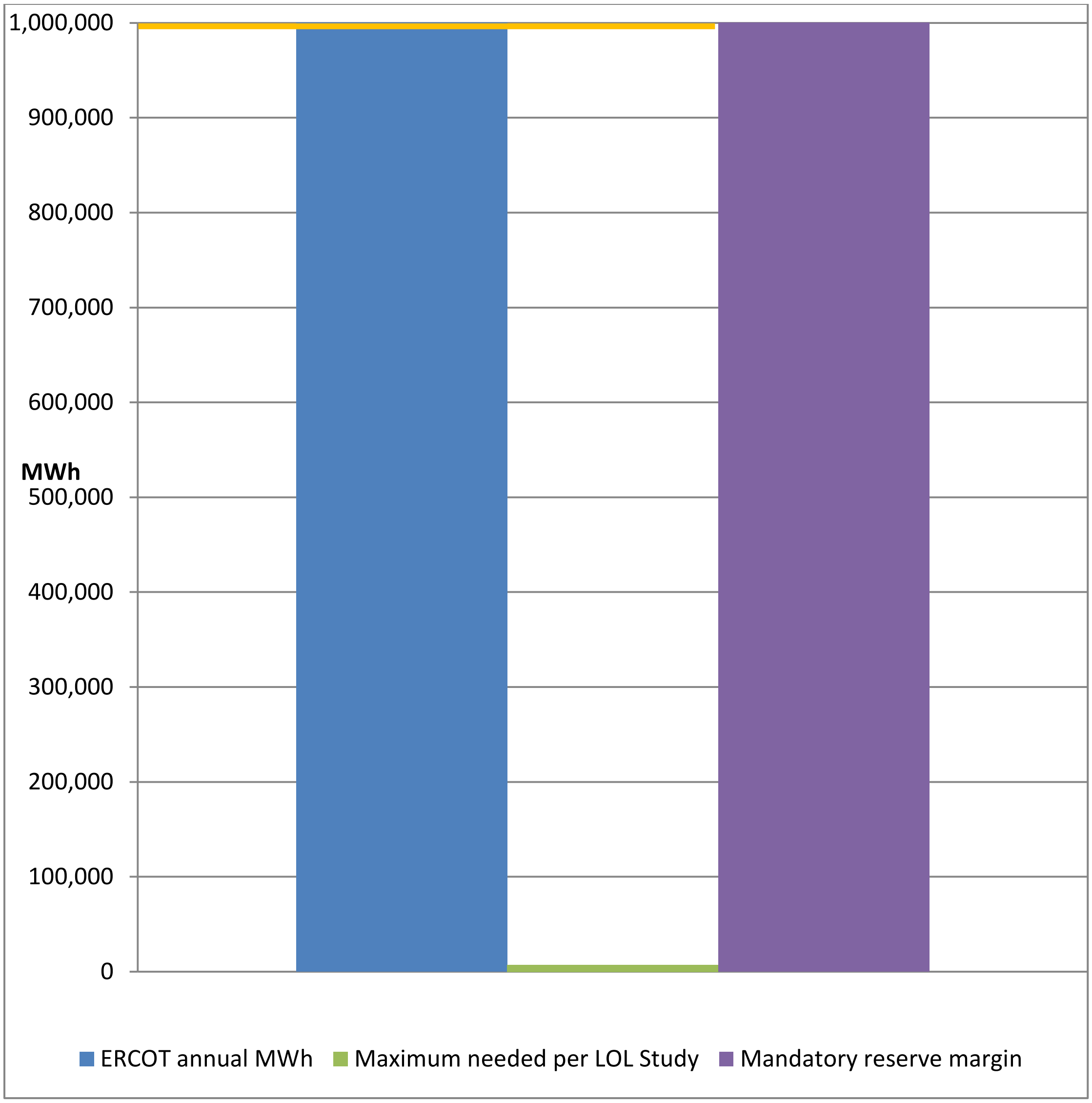


[66] The 2012 PJM market cost was $6.02/MWh. The assessment to PJM consumers was, 6.02/(47.77-6.02) = 14.2%. *supra* note 59 at 2. The total energy used in PJM in 2012 was 793.679 million MWh, *see Summer 2013 PJM Reliability Assessment*, June 6, 2013 at 2. The total capacity cost assessed in PJM in 2012 was therefore $6.02/MWh x 793.679 million MWh = $4.78 billion. In 2011 the PJM capacity cost was $9.72/MWh. See Monitoring Analytics, LLC, *2012 State of the Market Report for PJM*, at 15 in Table 1-8. At this cost of capacity in ERCOT the capacity assessment in 2012 would have been $3.16 billion per year.

Believe it or not, there is a column in the middle that shows the maximum amount needed by the LOL Study, but it is so small relative to the other columns you cannot see it. This next graph zooms in so that the top of the 15% mandatory reserve margin is the top of the graph in the hope that you will be able to see the column in the middle, note the red line, marking the same point on these first two graphs.

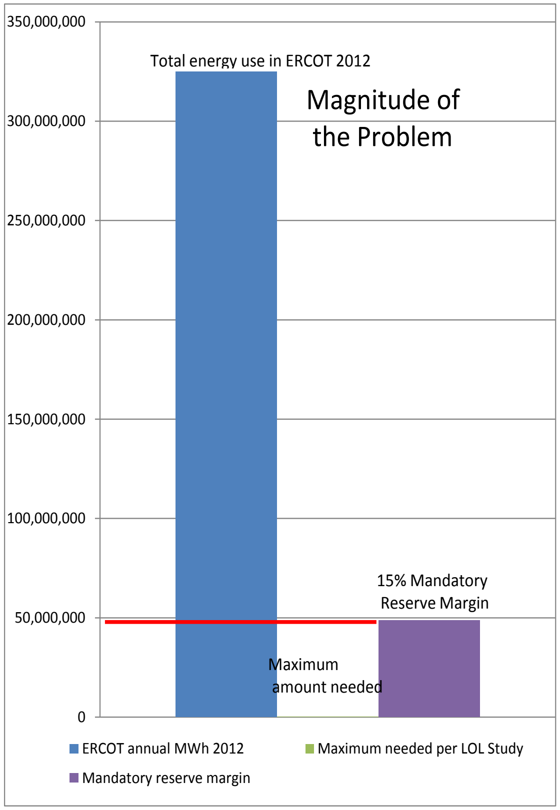


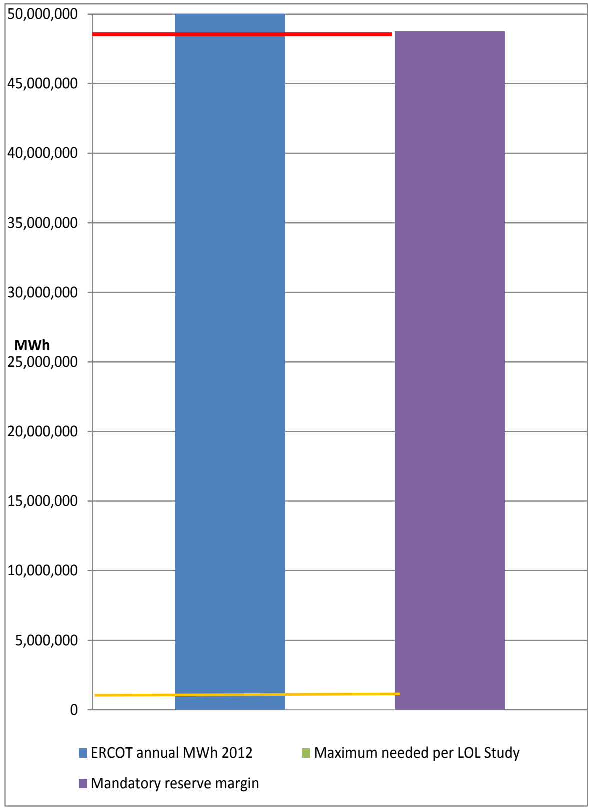
We still cannot see the column in the middle amounting to 7,108 MWh, the maximum amount that the LOL Study says we need to be able to make up in the absolute worst case scenario in 2016. Here, I've drawn another line to mark a common point on the graphs. It is drawn at the 1 million MWh point. In the third and final graph, with the 1 million MWh point now at the top of the graph, we can see just how much of a problem we are dealing with. Use the yellow line to give yourself a proper reference.

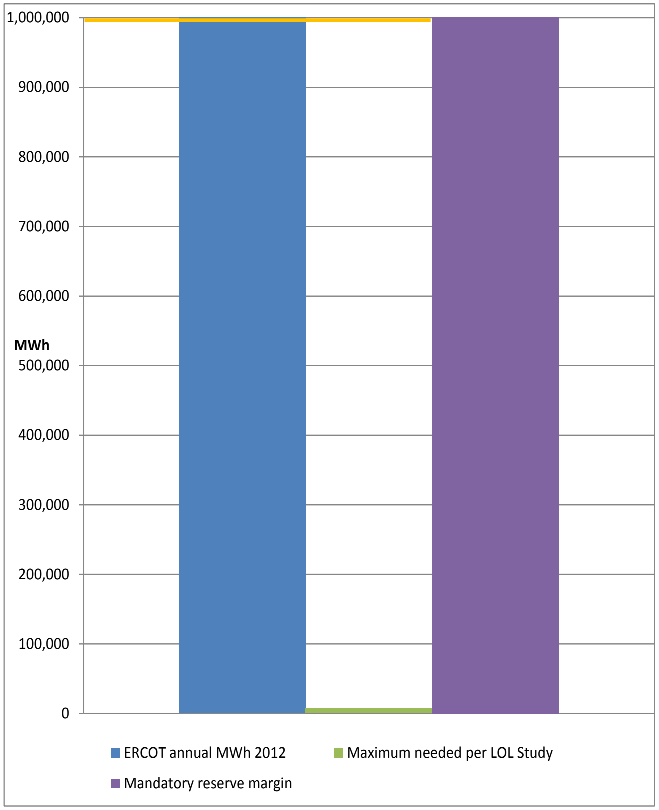


Now after zooming in twice, we can finally see just what 7,108 MWh of un-served energy actually looks like compared to how much ERCOT Texans would be assessed by a capacity market in order to hopefully avoid curtailing 7,108 MWh. The purple column (in the first two graphs) shows how much a 15% mandatory reserve margin totals; over 48 million MWh ($1.956 billion) that would be assessed to all ERCOT Texans. **REMEMBER: This is an extra charge equaling $6.02/MWh x 324.859 million MWh or $1.956 billion, it is *not* the purchase of extra electricity, it is just how the assessment is calculated.** The purple column in this last graph shows only 1/48 of that amount. Because it would be mandated to spend $1.956 billion on a mandatory reserve margin to cover the green column (and in this last graph, the purple column extends *48* times higher than you see in this graph), it is still less than 1/10 the cost of a capacity market to buy and build 1,500 MW of generation for the state, and let it sit idle 99.5% of the time.

I've consolidated these three graphs onto one page on the following page with explanation to ease their review.







These graphs show how small the problem is relative to how much generation capacity market advocates say must be purchased to increase reliability 0.00219%. The graphs zoom in from left to right, note the common marking lines. The first slide shows how many MWh were consumed in ERCOT in 2012, what the mandatory reserve margin would be at 15%, and in the center, the maximum amount that is required under worst case scenarios of only a 10.4% reserve margin. If we use the capacity payment from the PJM market in 2012 of $6.02/ MWh (total consumed), the total cost would have been $6.02/MWh x 324.859 MWh (total consumed in ERCOT) = $1.956 billion/year. Mandating a reserve margin of 15% in 2012 would have resulted in the $1.956 billion assessment associated with the purple column in order to protect against the *remotely possible* outage of 7,108 MWh (the green column). What is the ERCOT generating reliability? In 2012 it was 100%, but if the remotely *possible* outage in 2016 of 7,108 MWh is applied against 2012's total consumption of 324.859 million MWh, the reliability in 2016 would be (324,859,000 - 7,108)/324,859,000 = 99.99781%. The slides zoom in so you can see just how small the problem is. The capacity market advocates say we need to spend $1.956 billion annually to solve a *potential* 0.00219% reliability problem. Establishing a mandatory reserve margin requiring customers to purchase capacity is clearly an intrusive form of regulation because customers have no choice in the matter of how much reliability for which they are willing to pay. Instead, they will be *required* to pay the $1.956 billion as an assessment for the *mandatory* reserve margin under the guise of ensuring a 0.00219% improvement of reliability. How much would each of the 7,108 MWh cost? $1.956 billion/7,108 MWh = $275,183/MWh. A typical electricity bill is $0.10/kWh or $100.00/MWh.

The CRA Study results are so extreme, it suggests ERCOT should not rotate a load curtailment event among consumers, but rather make only one group of consumers suffer through the entire event because rotating the event will cost the Texas economy hundreds of millions of dollars.

The CRA Study says that if a load curtailment event were to occur, ERCOT should not rotate the event among consumers because it would cost about $171.15 million dollars more than not rotating. While the CRA Study itself does not calculate this value, the numbers used and methods employed by CRA in their study produce this result. This implies that either ERCOT's procedures of rotating a load shed are terribly wrong, or the values used by CRA in their study are terribly wrong.

The CRA Study used an average dollar per un-served MWh for ERCOT consumers of $85,000/MWh. This value was based on the 30-minute duration of outages suffered because of ERCOT and REPs policies of rotating a load shed. Recall that CRA assumes an approximate 3 hour outage[67] but uses 30 minute duration values because of these rotation policies and consequently determines an average dollar per un-served kWh from values found in the 30 minute column of CRA Study Table 4. If we compare the difference in $/kWh from CRA Study Table 4 for 30-minute outage and four-hour outage values (for simplicity since 3 hour values are not in the table), we see that the 30-minute values are all higher than the four-hour value. If we look at the ratio, just for small C & I, the four-hour cost is $326/kWh while the 30-minute cost is $590/kWh. For simplicity, if we assume the four-hour value to be used for a three-hour event, the ratio between rotating a load shed and not rotating a load shed is 590/326 or 181%.

If we believe the CRA Study results we should ask; what is the overall cost to the Texas economy because we rotate a load shed instead of making one group of customers suffer the entire outage? The scenario I describe in the main body and *CRA's assumption*, is something like this: 1,500 MW of load must be shed for 2 hours so four different groups all lose 1,500 MW of power for 30 minutes each over the 2 hour period.

Using the CRA Study average dollar per un-served MWh of $85,000/MWh, determined from 30-minute outage values, a 3-hour (CRA Study value) outage would cost $85,000/MWh x 1,500 MW x 3hrs or $382.5 million. With no rotating load shed, the cost would be (only using the difference in small C&I values) $382.5 million/1.81 or $211.35 million. This means, using CRA's dollar per un-served MWh of $85,000/MWh, rotating the CRA standard curtailment event that they assume, costs the Texas economy $382.5 million - $211.35 million for a total cost of $171.15 million more than not rotating. If we were to weight the values including residential customers, the cost only becomes greater because the residential customer ratio is 4.67/1.38 or 3.38.

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[67] The three hour duration is not supported by actual summer load curtailment events. Even in the extreme weather summer of 2011, no load curtailment occurred. As shown in section 2 of this analysis, the typical load profile peaks and then recedes over a time period of less than 3 hours so the need for curtailment would likely be less than 3 hours. Also, recall that the CRA Study relies *only* on summer afternoon weekday values in its study.

Either CRA's numbers are way off, or our policy of rotating a curtailment event would cost the Texas economy hundreds of millions of dollars if one were to occur. I've pointed out errors in the CRA Study of how their average dollar per un-served MWh of $85,000/MWh is unreasonably high, but even with the corrections it is likely too high and this is likely because the very subjective nature of the surveys that the Berkeley Study was asked to evaluate by the DOE. If we examine the cost of rotating a curtailment event with the figure of $3.66 per kWh (as discussed above), the cost of rotation drops to 3,660/85,000 x $171.15 million = $7.36 million, and this figure is still susceptible to the subjective evaluation from surveys that a 30-minute outage duration costs more per kWh than a three-hour outage. Using an average dollar per un-served kWh of $3.66/kWh makes much more sense to me. Rotating a load shed *might* cost more than making only one group of people suffer through the entire event, but not in the hundreds of millions of dollars. This also introduces a final important point to consider: It would be far less expensive if ERCOT were to implement an aggressive demand response program by recruiting customers willing to be curtailed in exchange for a payment approximately equal to their value of lost load.